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ALBERTA ENERGY

1993-1994

ANNUAL REPORT

Alberta
ENERGY



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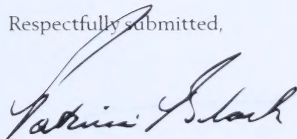
September 1995

The Honourable Stanley S. Schumacher
Speaker of the Legislative Assembly
Province of Alberta

Mr. Speaker:

I have the honour of submitting the Annual Report of the Alberta Department of Energy for the fiscal year ending March 31, 1994.

Respectfully submitted,

A handwritten signature in dark ink, appearing to read "Patricia L. Black". The signature is fluid and cursive, with a large, sweeping initial "P".

Patricia L. Black
Minister of Energy

September 1995

The Honourable Patricia Black
Minister of Energy

Dear Minister:

It is my pleasure to submit the Annual Report of the Alberta Department of Energy for the fiscal year 1993-94.
The report contains a summary of the Department's activities, revenues and expenditures for the year.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "R. M. Hyndman", followed by a long horizontal line that ends in a small upward-pointing arrow.

Richard M. Hyndman
Deputy Minister of Energy

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Minister's Message

Alberta has entered a new era of government in which we are redefining the way we conduct the people's business. The goal is to find new and better methods to provide essential services at lower cost — that is, to get more value for each tax dollar. This is all part of the Alberta government's plan to reduce spending and eliminate the provincial deficit.

I am pleased to report that the Energy Ministry is well on the way to implementing this new approach to conducting government business. Our three-year business plan, which was made public in February, outlines the long-term goals and program objectives for the Ministry and spells out the spending cuts we will make. A second initiative we are undertaking is the restructuring of the Ministry itself. This is an important and integral part of the three-year plan.

In preparing this plan, we had to ask ourselves some basic questions. What are our objectives? What do we want to accomplish? Can some of our services be provided equally well by the private sector? Where can we cut costs to help meet the government's budget goals?

The plan identifies two primary goals for the Energy Ministry. One is to maximize the value of Alberta's energy and mineral industries to provide greater benefits to Albertans. The second is to achieve greater efficiency and productivity in the Ministry's internal operations.

We will be taking a number of steps to achieve the first goal. These include working with industry and other governments to prepare a vision and action plan to develop Alberta's oil sands, and developing a coordinated energy research strategy, again in consultation with industry and other stakeholders.

We also will strive to provide an attractive investment climate, a streamlined regulatory framework and a stable, competitive fiscal structure. In this regard, we have completed the first phase of

our regulatory review, which is aimed at eliminating unnecessary regulations and streamlining the regulations that are required. Next, we will ask for the view of various stakeholders on our draft action plan, and then we can begin implementing the changes.

Simplifying the natural gas royalty administration, which came into effect in January, is another example of how we are improving our business processes. The new system is expected to reduce paper work by more than 70 per cent and result in industry savings of about \$25 million per year.

Under the three-year plan, the Ministry's budget will be reduced by 23 per cent over the next three years, from \$95 million to \$73 million. It is worth noting that most of this saving — about 74 per cent — will be achieved through lower administration costs, greater efficiency and less duplication. The most difficult part of the plan to carry out will be the elimination of 281 positions; we are doing all we can to provide career counselling and outplacement assistance.

The Ministry will save more than \$1 million alone through discontinuing the main programs offered by the Energy Efficiency Branch, including energy audits, the toll-free information line and the publications program. The private or not-for-profit sectors will take over these programs.

A further \$4.5 million will be cut from the Ministry's budget through a reduction in research funding. In oil sands, research funding will focus on results that can achieve economic objectives, while the government's support for coal research will take into account the development strategy being prepared in consultation with the coal industry.

To achieve the second Ministry goal — greater efficiency and productivity — we are carrying out the most comprehensive restructuring of the Ministry ever undertaken. The changes will give us a leaner, more integrated and more business-like organization.

In the new organizational structure, the Energy Resources Conservation Board will be merged with the Public Utilities Board to form a single quasi-judicial regulatory agency called the Alberta Energy and Utilities Board. This merger will reduce overlap and duplication, providing industry and other stakeholders with a one-window approach.

Two other agencies — the Alberta Oil Sands Technology and Research Authority (AOSTRA) and the Alberta Oil Sands Equity — will be brought into a new division in the Energy Department called Oil Sands and Research. Incorporating AOSTRA into this new division will bring greater focus to the Ministry's oil sands policies and initiatives. The restructuring also calls for creating a volunteer panel of industry Experts to advise the Department on priorities and strategies for government funding of energy research.

Duties of other existing divisions in the Department will be brought together in three other new divisions — Operations and Support, Strategic Resources and external Relations and Communications.

We were just beginning to implement these changes at the end of the 1993-94 fiscal year. The whole process will take some time to complete, but when the task is finished we will have a lean, efficient Ministry that will work more effectively with industry while continuing to protect the interests of the resource owners, the people of Alberta.

Change is never easy, and at times it can be truly difficult. I am very grateful, therefore, to the officials and staff of the Ministry for their understanding and assistance as we carry out this task. The end result, I believe, will benefit government and industry alike.

Patricia Black
Minister of Energy

Organizational Structure

The Alberta Department of Energy has 4 basic functions. It grants mineral rights and administers mineral agreements on behalf of the province; it provides policy recommendations and advice on energy to the government; it advises on, establishes and administers the fiscal regimes and royalty systems through which the people of Alberta — the resource owners — receive fair return on their resources; and it administers energy-related research, development and conservation programs.

In addition to the Department, the Minister of Energy had responsibility in 1993-94 for 4 reporting boards and agencies:

- Alberta Oil Sands Equity
- The Alberta Petroleum Marketing Commission
- Alberta Oil Sands Technology and Research Authority
- The Public Utilities Board.

The Energy Resources Conservation Board reported to Executive Council through the Minister of Energy.

The Department was divided into 5 divisions. The Department's organizational structure also included the Communications Branch and Legal Services, both reporting to the Deputy Minister.

Mineral Resources Division — This division is responsible for developing and administering energy and other mineral leasing policies to optimize Alberta's mineral supply and the province's corresponding economic, environmental and employment interests. The division ensures that the Alberta Geological Survey effectively and efficiently supports provincial geological requirements. It consults with other governments on leasing-related and geological survey policies and administrative practices.

Mineral Revenues Division — This division is responsible for the management of programs established to generate and collect mineral revenues and for providing the assurance that these programs are consistent with provincial policies and the business environment. It manages a number of incentive programs that enhance exploration and development of minerals in Alberta and their extraction.

Markets, Supply and Industry Analysis Division — This division serves the Alberta public interest through analysis, policy development, making recommendations on legislation and programs, and providing information in the areas of markets, regulatory matters, industry financial performance, supply economics, resource revenue forecasting and electricity policy. The division provides advice on how to optimize the value and benefits that Albertans receive as owners of their mineral resources and consumers of oil, gas, coal and electricity.

Sustainable Energy Development Division — This division works to ensure the sustainable development of Alberta's energy resources. It provides policy advice and administers programs concerning energy efficiency. It also provides policy advice concerning environmental issues affecting energy production and use. The division undertakes analysis and provides policy advice concerning development of non-conventional resources, including oil sands and renewable energy. It also provides advice on research and technology and administers programs involving coal, hydrogen and renewable energy. The division has extensive liaison with other Alberta government departments and agencies and with industry, non-governmental organizations and consumers.

Finance and Administration Division — This division provides services in the areas of finance, internal audit, automated systems, accommodations, records management, the Crown Land Registry, document and information support, and human resource programs.

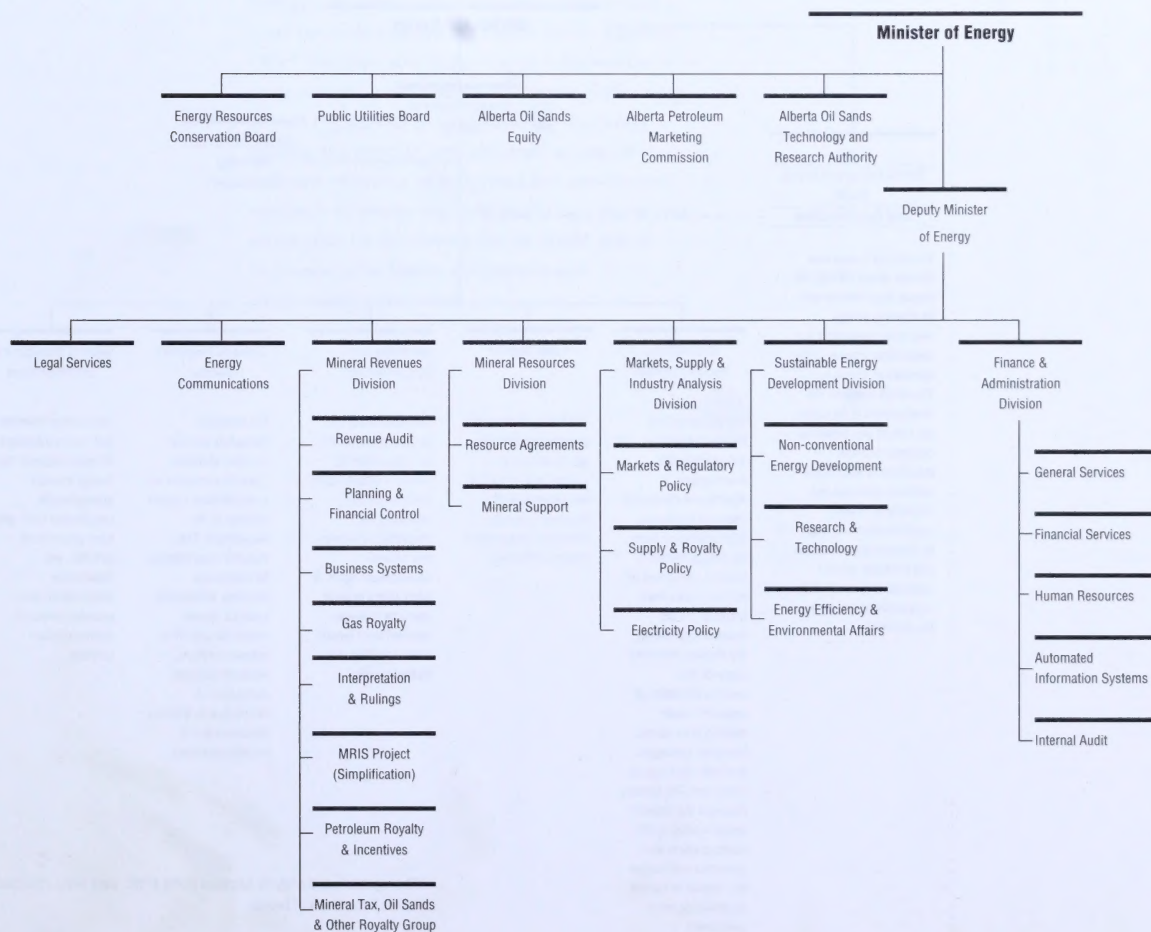
Communications — The Communications Branch provides an array of services to help ensure that the general public is kept informed of the Department's activities and responsibilities. The branch prepares written material for release to the news media and is responsible for advertising, production of publications and development of displays. The branch provides writing and editing services and coordinates printing, graphic design and photography services. In cooperation with divisional staff, the branch develops and implements public awareness campaigns and responds to enquiries from the media.

Legal Services — This area provides legal advice and assistance on all matters pertaining to energy.

Restructuring — A major restructuring in the Ministry of Energy was announced on February 11, 1994. The changes, to go in effect during the 1994-95 fiscal year, were designed to reduce the Ministry's 5 reporting agencies to 1 and emphasize "one-window" access and a more streamlined and efficient regulatory process for industry. Key features of the restructuring included:

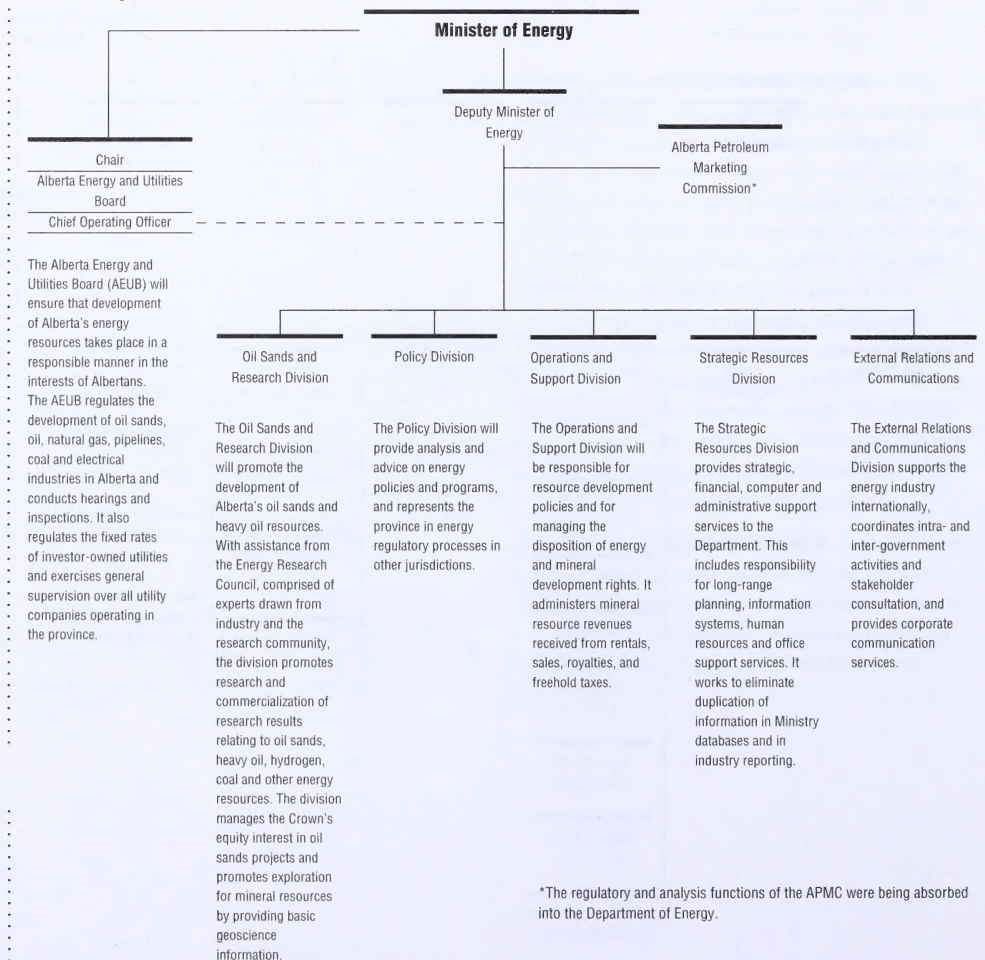
- Amalgamating the Energy Resources Conservation Board (ERCB) and Public Utilities Board (PUB) into a single quasi-judicial regulatory agency called the Alberta Energy and Utilities Board (AEUB).

Figure 1
Organizational Chart
Changes planned following
February 11, 1994
Restructuring Announcement



- A study into the feasibility of allowing the private sector to market the Crown's royalty crude.
- Discontinuing separate agency status for the Alberta Oil Sands Technology and Research Authority (AOSTRA).
- Discontinuing separate agency status for Alberta Oil Sands Equity (AOSE).
- Creating a new division within the Department called Oil Sands and Research. For the first time ever, the province's involvement in energy research and its equity investments in oil sands and heavy oil will be brought together and coordinated. AOSTRA and AOSE activities will form part of this division.
- Appointing a volunteer panel of industry experts to be collectively known as the Energy Research Council. The Council will advise the Department on priorities and strategies for government funding of energy research.
- Creating a new division within the Department called Operations and Support. This division will bring together the bulk of the work now performed across three divisions in the Department. The Operations and Support Division will be responsible for all activities related to mineral leases, and royalty assessment and collection.

Figure 2
Organizational Chart
 (As of February 11, 1994)
 Changes planned following
 February 11, 1994
 Restructuring Announcement



- Creating a new division within the Department called Policy. It will include the activities previously performed by Markets, Supply and Industry Analysis Division and bring in other policy functions.
- Creating a new division within the Department called Strategic Resources. This division will be responsible for automated information systems, human resources and office support services.
- Creating a new division called External Relations and Communications within the Department. This division will be responsible for coordination with other government departments, public information, Calgary Information Centre, education and promotion activities, energy trade missions and visitors' program.

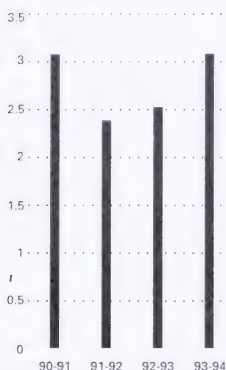
The restructuring represents only one component of a longer-term strategy to redefine the Ministry of Energy's operational interface with industry and meet the budget reduction targets for the Ministry. Other activities now under way to achieve these two goals include: a comprehensive review of all energy-related regulations to streamline the regulatory process and provide "one-window" access for industry; pursuing an integrated and coordinated approach to energy research; outlining a vision and action plan for developing the oil sands; and re-engineering the Ministry's business and administrative processes.

Revenues

As owners of the province's natural resources, the people of Alberta are entitled to a fair return on the production of natural gas, coal and other minerals. As a representative of the people, the Alberta Government, through the Department of Energy, has the responsibility to develop and manage programs to determine these revenues and to collect them.

Figure 3
Energy Revenues

Billion dollars



Total Energy Revenues — Crown revenue in 1993-94 from all mineral resources was derived mainly from royalties and sales of Crown agreements for development of these resources. Net revenue for 1993-94 climbed to \$3.16 billion from \$2.5 billion the previous fiscal year, mainly because of substantially higher royalties for natural gas and a major increase in bonuses and sales of Crown leases. (Figure 3)

Crude Oil Royalties — The volume of Crown conventional oil produced in 1993-94 increased by 5 million barrels from the previous fiscal year to a total of 279.6 million barrels. New oil, primarily from reservoirs discovered since 1974, represented 79.1 per cent of the Crown volume produced. Light and medium crude oil represented 86.9 per cent of total Crown production.

The 1993-94 period was the first complete fiscal year after the January 1, 1993 implementation of the price-sensitive royalty regime for conventional crude oil. The gross Crown royalty share — Alberta's share before deductions — represented 19.9 per cent of the volume produced during the fiscal year compared with 23 per cent in 1992-93. This 7.5 million barrel royalty volume reduction resulted from a combination of structural royalty changes and lower oil prices.

Crown Conventional Oil is oil recovered under authority of a Crown lease, using primary production techniques.

Net Royalty Volumes and Revenue — The net Crown royalty share reflects deductions from the gross Crown royalty share for Enhanced Oil Recovery relief and the Oil Royalty Holiday programs that encourage exploratory and development drilling. The net share totalled 14.7 per cent, a volume of 41 million barrels. This compares with a rate of 18.3 per cent and a volume of 50.2 million barrels in 1992-93. Deductions increased by 1.7 million barrels in 1993-94 compared with the previous year primarily due to the high level of development oil well drilling incentives.

Revenue from the sale of royalty oil by the Crown totalled \$766.4 million compared with \$1,008.5 million for 1992-93. This decrease resulted primarily from the effect of lower world oil prices on royalty volumes and sales values.

Enhanced Oil Recovery (EOR) — EOR projects are undertaken to increase the recovery percentage of the original oil in place in a particular reservoir. An average of about 46 per cent of the oil in a reservoir can be recovered using conventional primary and secondary recovery methods. With tertiary recovery methods, an additional 14 per cent of the oil may be recovered on average. These methods include injection of gas and natural gas liquids which mixes with the reservoir oil. Additional natural gas, called "push gas," is then injected to force this mixture and the resident oil to producing wells.

These tertiary methods are expensive, and the Crown shares in certain costs by reducing royalties on the tertiary oil produced from the approved EOR project. These royalty reductions are authorized under section 11 of the Petroleum Royalty Regulation, and effective January 1994, under the Enhanced Recovery of Oil Royalty Reduction Regulation.

For the 1993-94 fiscal year, industry received \$120 million in royalty relief. This relief is provided in-kind, meaning that EOR project participants receive oil in lieu of cash. For the 1992-93 fiscal year, industry received \$130 million in relief. The decline in relief for the approved projects in 53 pools was primarily due to declining costs as these projects mature.

Roughly 105,000 barrels per day of tertiary oil were recovered from these projects in 1993-94, compared to 120,000 barrels per day in 1992-93.

Figure 4

	1993-94	1992-93
	(\$ millions)	
Crude Oil Royalty Revenue	1,066	1,310
Deduct		
EOR Royalty Relief	120	130
Other	180	171
Crude Oil Royalties (net)	766	1,009

Note: EOR relief is for volumes only. It does not include any cash adjustments. In addition, tertiary oil production is based on established tertiary factors approved for each project.

Synthetic Crude Oil and Bitumen Royalties —

Revenue from the production and sale of synthetic crude oil and bitumen in 1993-94 totalled \$66 million. Revenues were relatively unchanged from the previous fiscal year despite soft world oil prices during the second half of the year. The two Fort McMurray synthetic crude oil sands plants accounted for approximately 70 per cent of the total oil sands royalty revenues. Both plants recorded record high levels of production. (See Non-conventional Oil Development — Page 16.)

Synthetic Crude Oil is produced from a heavy hydrocarbon called "bitumen" which saturates beds of sand in the Athabasca, Peace River and Cold Lake deposits in Alberta. At room temperature, bitumen has the consistency of very cold molasses.

During processing, the carbon level of the bitumen is reduced and the hydrogen level increased. The result is synthetic crude which has properties similar to a high-grade conventional crude oil.

Natural Gas and Byproduct Royalties — Overall gross natural gas and byproduct royalty revenues climbed to \$1.9 billion for 1993-94 from \$1.5 billion in the previous fiscal year due to a tighter market balance and strengthening natural gas prices. Net natural gas and byproduct royalties increased to \$1.4 billion from \$1.1 billion in the previous fiscal year.

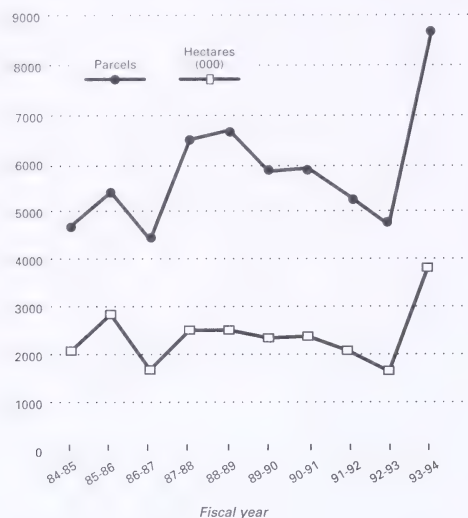
Gas Cost Allowance — Gas Cost Allowance is a deduction allowed by the Crown for gathering, compressing and processing the Crown's share of natural gas and associated byproducts. It is deducted from royalties payable on a monthly estimated basis. The actual allowance is then calculated and reconciled for each calendar year. The allowance is subtracted from gross royalties to arrive at net royalties payable. In 1993, Gas Cost Allowance totalled \$517 million, up 4 per cent from \$497 million in 1992.

Figure 5

Gas Royalties	1993-94	1992-93*	% Change
	(\$ millions)		
Gas — New	1,098	839	30.9
Gas — Old	491	348	41.1
Pentane — New	130	142	-8.5
Pentane — Old	86	118	-27.1
Butane	51	50	2.0
Propane	69	57	21.1
Sulphur	2	12	-83.3
TOTAL	1,927	1,566	23.1
Deduct			
Gas Cost Allowance	517	497	4.0
Net Gas Royalties	1,410	1,069	31.9

* The 1992-93 gross royalties and gas cost allowance are restated from the previous annual report to include \$80 million in custom processing fees, an allowable cost deduction against gross gas royalty. These fees were not included in the figures provided in the 1992-93 annual report.

Figure 8
Petroleum and Natural Gas Parcels and Hectares (000) Sold



Primary Term Expiries — Shortly before a petroleum and natural gas lease reaches the end of its primary term, the lessee may apply to the Operations and Support Division to have the lease continued, based on proven productivity. Petroleum and natural gas rights considered by the division to be productive are continued to the base of the deepest productive zone. Unproductive rights revert to the Crown.

During the 1993-94 fiscal year, 5,967 primary-term leases comprising 1,880,064 hectares, expired. Approximately 78 per cent, or 1,465,512 hectares, were not proven productive and reverted to the Crown. Figure 9 shows a breakdown of actions on expiring leases.

Figure 9
Expiring Primary Term Petroleum and Natural Gas Leases in 1993-94 Fiscal Year

	Leases	Hectares	Per Cent of Total Hectares
Continued Based on Proven Productivity	787	265,070	14.10
Continued Based on Drilling Operations Near the End of the Term	203	55,936	2.98
Continued As Potentially Productive	324	84,842	4.51
Term of Lease Extended	12	8,704	0.46
Not Continued (Cancelled)	4,641	1,465,512	77.95
Total	5,967	1,880,064	100

Continued Leases — The Mines and Minerals Act provides for the monitoring of petroleum and natural gas leases that have been continued. When productivity of a lease is in doubt, the Minister may serve a one-year notice stating that the lands or rights will revert to the Crown unless the lessee can provide evidence of productivity. During the 1993-94 fiscal year, 749 non-productivity notices were served, affecting 334,948 hectares.

In addition, 1,295 non-productivity notices of one year in duration served in the 1992-93 fiscal year expired, affecting 384,372 hectares. As a result, 32 wells were drilled and an additional 40 wells were re-entered or recompleted prior to the end of fiscal 1993-94. Eighty per cent of the affected hectares reverted to the Crown and thereby became available for further acquisition.

Offset Drilling Obligations — When a well is drilled on freehold rights and is put on production, it has the potential to drain petroleum or natural gas from adjacent Crown mineral rights. This creates an offset drilling obligation for Crown leases. To protect the interests of Albertans, the Crown lessee is given the option of drilling a well, paying compensatory royalty in lieu of drilling, or surrendering lands or rights to satisfy the offset obligation.

During the 1993-94 fiscal year, 676 freehold oil wells were reviewed and 67 oil offset default notices were served. As a result of these notices, 28 lessees elected to pay compensatory royalty, 20 surrendered the petroleum and natural gas rights, 13 drilled wells, and 6 notices were withdrawn.

During the 1993-94 fiscal year, 441 freehold gas wells were reviewed and 92 gas offset notices were served. As a result of these notices, 24 lessees elected to pay compensatory royalty, 39 surrendered the petroleum and natural gas rights, 13 drilled wells and 16 notices were withdrawn.

During the fiscal year, 1,784 petroleum and natural gas posting requests were reviewed and 36 oil offset and 75 gas offset notices were served. As a result, 63 lessees elected to pay compensatory royalty, 24 drilled wells, 6 surrendered the petroleum and natural gas rights, 16 notices were withdrawn, and 2 notices were extended to October 1994 to drill wells.

Unit Agreements — A number of parties, including the Alberta government, can have an interest in a single oil or gas pool. Unit agreements are useful tools for achieving the highest possible oil and gas recovery while ensuring that all parties recover an equitable share of the resource.

All proposed unit agreements in the province are reviewed, negotiated and executed on behalf of the Minister by the Operations and Support Division. During the 1993-94 fiscal year, 17 new unit agreements became effective and 4 existing ones were enlarged. At fiscal year-end, the Alberta government was party to 616 units.

Oil Sands Leases — During the 1993-94 fiscal year, the Operations and Support Division administered 336 oil sands leases. One-third of these leases are in their second 21-year term and will expire between 1996 and 2012. Each second-term lease is required to be in production at a specified capacity in order to enter its third term. These leases encompass approximately half of both surface-mineable and non-surface-mineable oil sands reserves. During the fiscal year, only two second-term oil sands leases produced at or above their prescribed capacity. Four other second-term leases produced at less than their specified capacities, while the balance did not produce at all.

Two public offerings of oil sands were held early in 1994, with seven leases totalling 2,597 hectares sold for \$425,000.

Coal, Metallic and Industrial Minerals — The Operations and Support Division issued 2,407 metallic and industrial minerals permits during the

1993-94 fiscal year. This brought the total number of active permits to 3,804, covering an area of 32.8 million hectares, which represents about 65 per cent of the Crown mineral land base. The exploration targets for these agreements are primarily diamonds and gold.

A public offering of metallic and industrial minerals permits was held in February 1994, the first in almost a decade. Sixteen permits were sold for \$105,000 in the surface-mineable oil sands area around Fort McKay. Companies working in this area have been attracted by discoveries of gold in limestone in northeastern Alberta.

The number of coal leases administered by the division decreased during the fiscal year as a number of companies rationalized their lease holdings. There were 1,700 active coal leases covering 664,000 hectares at the end of the fiscal year, compared to 2,100 leases on 894,000 hectares the previous year. No new coal leases were issued, but 302 were renewed.

The Division administered 70 ammonite shell agreements comprising 7,860 hectares of rights during the fiscal year. Ammonite shell of jewellery quality is Alberta's gemstone. It is also a palaeontological resource under the Historical Resources Act.

Industrial mineral leases holdings remained relatively stable during the year. The Division administered 11 salt leases comprising 5,100 hectares and 89 quarriable mineral leases comprising 15,520 hectares.

Natural Gas Storage — In response to the increasing demand by the oil and gas industry to acquire Crown agreements for natural gas storage in underground reservoirs, an interdepartmental Gas Storage Task Force has been reviewing existing tenure and royalty policies. A draft report was circulated in December 1993 to industry for their input. Amendments to the Mines and Minerals Act were passed in the spring session of the Legislature to clarify the rights of the Crown with respect to storage where the Crown owns the mineral rights.

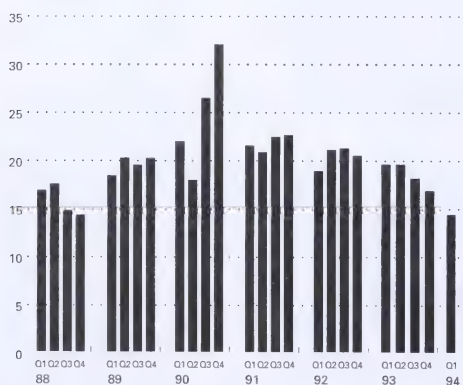
Oil

The average price of crude oil over the 1993-94 fiscal year was US\$17.23 per barrel, using as a benchmark West Texas Intermediate prices reported on the New York Mercantile Exchange (NYMEX), for crude oil delivered at Cushing, Oklahoma. This price represented a decline of almost US\$3.50 from the previous fiscal year.

Crude oil prices were around the US\$20 level at the outset of the fiscal year. Weak supply-demand fundamentals, however, exerted downward pressure on world oil prices, which dropped US\$6 by the fall. In December prices fell to a five-year low of US\$13.91 for one day.

World demand for crude oil during 1994 declined by 0.3 per cent — the first such annual decrease since 1985. The weak demand became evident in the fall. At the same time, strong growth in oil supply caused a significant supply-demand imbalance. Several producing areas, such as the North Sea, hit new peak output levels. The supply-demand imbalance added to the already weak prices that evolved in the summer and caused prices to slide.

Figure 10
West Texas Intermediate Crude Oil Prices
US \$ per barrel



For Alberta producers, the decrease in crude oil prices was partly offset by the weaker Canadian-U.S. dollar (from .81 in 1992-93 to .76 in 1993-94).

Crude oil prices are typically set in U.S. dollars. As the exchange rate declines, the Canadian dollar equivalent oil prices rise. Consequently, although the annual average U.S. dollar oil price declined by US\$3.50, the Canadian dollar equivalent price to Alberta producers only declined by \$3 rather than the potential \$4.40 if the exchange rate had remained at .81.

Markets and Pipelines — Shipments out of Alberta continued to be restricted due to insufficient pipeline capacity. Interprovincial Pipe Line, which carries about 85 per cent of Alberta's crude oil to markets beyond the province, had to apportion shipping requests throughout the year.

The level of apportionment averaged 37 per cent during the fiscal year. This level, however, overstates the actual shortfall as producers tend to over-nominate their shipping requirements to secure as much throughput capacity as possible after apportionment. In most months, the apportioned crude oil could be shipped to alternative lower valued markets using other pipelines. In some months, however, total pipeline capacity out of Alberta was insufficient to meet all shipping needs and small portions of crude oil were shut-in.

This uncertainty about shipments continued to hinder Alberta producers' ability to market crude oil. Buyers were able to negotiate price discounts to compensate for the supply risks. Several pipeline expansion proposals were discussed during the year. In the fall, the National Energy Board approved an expansion for Interprovincial that will allow capacity out of Alberta to increase by 175,000 barrels. The project, which is estimated to cost \$425 million, is scheduled to be finished by January 1995.

Production — Alberta's total production of crude oil and equivalent — conventional light, medium and heavy, bitumen, synthetic and condensate and pentanes — rose for the second year in a row.

Alberta's crude oil production, calculated on a calendar-year basis, totalled 1.45 million barrels a day in 1993, up 3.6 per cent from 1.40 million barrels a day in 1992. Declining heavy production was more than offset by a combined increase in other categories. A number of factors were responsible for the higher production:

- drilling increases and well reactivations stimulated by government programs;
- full scale production from Shell's Caroline project which added significant condensate and pentanes production;
- industry's property rationalization which transferred many non-active wells to smaller companies that are now working their new acquisitions.
- blanket application of "good production practice" (GPP) statutes to Provost area oil production.

Conventional light and medium oil production totalled 726 Mbpd (thousand barrels per day) up 5.2 per cent from 690 Mbpd in 1992. Light and medium crude represents 50 per cent of Alberta's oil production.

Conventional heavy oil production dropped to 4.9 per cent to 214 Mbpd in 1993 from 225 Mbpd in 1992. Bitumen production totalled 132 Mbpd, up 4 per cent from the 1992 level of 127 Mbpd. Production of synthetic crude oil climbed to 244 Mbpd, up 3 per cent from 237 Mbpd in 1992.

Pentanes plus volumes increased to 138 Mbpd, up 7 per cent from 129 Mbpd in 1992. Alberta's pentanes production is collected primarily as a co-product of natural gas processing. It is also collected as condensate at the wellhead and as a result of crude oil processing.

Figure 11
Average Daily Production of Crude Oil

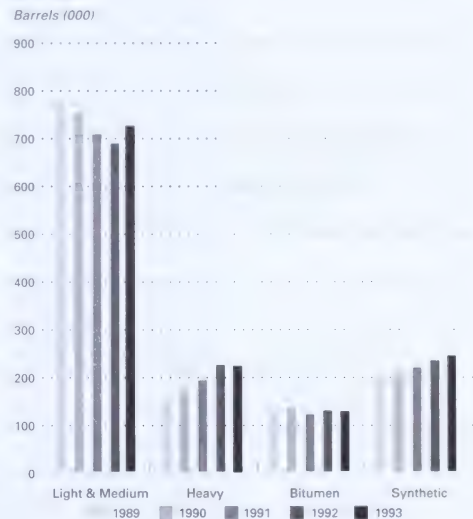


Figure 10 shows a 5-year comparison of crude oil production.

Conventional Reserves — Alberta's remaining reserves of conventional oil (crude oil that can be produced with normal production operations) totalled 2.69 billion barrels at the end of 1993, down 3.2 per cent from the previous year. Light and medium oil accounted for 86 per cent of the reserves and heavy oil made up the balance.

At today's rate of conventional oil production, Alberta's reserves-to-production ratio is just under eight years. The remaining ultimate potential production of conventional crude oil (including potential discoveries) is estimated by the Alberta Energy and Utilities Board at 7.1 billion barrels.

Non-conventional Oil Development — As the supply of conventional oil in North America is depleted, consumers will be able to turn to non-conventional sources of petroleum to avoid a growing dependence on resources outside North America. Fortunately, Alberta has huge deposits of oil sands that underlie about 77,000 square kilometres in the province and contain about 1.7 trillion barrels of oil in place.

In encouraging the development of this oil sands resource, the Government of Alberta's main objective is to promote sustainable and environmentally sensitive development using the best available technology. Alberta's strategy of oil sands development is aimed at unlocking the massive resource potential for the long-term prosperity of the province.

Oil Sands Initiatives — On December 21, 1993, the Province of Alberta sold a 5 per cent interest in the Syncrude Project to Murphy Oil Company of Calgary, a wholly owned subsidiary of Murphy Oil Corporation of El Dorado, Arkansas, for \$150 million. The province retains an 11.74 per cent interest in Syncrude.

Alberta continued its involvement in the National Task Force on Oil Sands Strategies during the year. The task force was created in January 1993 to identify new concepts, technologies and strategic approaches for further development of Alberta's oil sands resource. The task force is industry-led and includes representation from all industry stakeholders plus the governments of Alberta and Canada.

Non-conventional Activity — Prices for heavier crudes and bitumen fell slightly in 1993-94 although they did not decline to the same extent as light crude oil and synthetic crude oil. The light/heavy oil price differential dropped from a fiscal year average of more than \$7.50 a barrel in 1992-93 to less than

\$6.50 in 1993-94. Lower heavy oil prices and pipeline capacity constraints problems caused some oil sands producers to delay proposed expansions.

In 1993, Suncor Inc. Oil Sands Group produced a record 22.1 million barrels of synthetic crude oil, including 1.4 million barrels of intermediate product. Syncrude Canada Ltd., the largest synthetic crude oil producer in the world, produced 67 million barrels of synthetic crude oil. It was the company's fourth consecutive year of record-setting production levels. The more than 89 million barrels of synthetic crude oil produced by the two oil sands mining operations met approximately 16 per cent of Canada's total crude oil requirements. Bitumen production from in situ projects totalled over 143,400 barrels per day (53 million barrels a year).

The Lloydminster Bi-Provincial Upgrader, which officially opened in November 1992, produced more than 43,000 barrels per day of synthetic crude oil (more than 16 million barrels a year), surpassing expectations. Nonetheless, the plant, jointly owned by the federal, Saskatchewan and Alberta governments and Husky Oil Ltd., experienced net operating losses due to a narrowing of the differential between the price of the heavy oil feedstock and the price of the synthetic crude produced, in addition to higher costs for the natural gas used in the production process.

Non-conventional Reserves — Remaining established reserves of crude bitumen that can be recovered with current technology from deposits under active development include 2.73 billion barrels for surface-mining projects and 0.3 billion barrels for in situ projects. These represent a supply of 23 years at 1992 production levels. The remaining ultimate potential for production of crude bitumen was 307 billion barrels at year-end 1992.

In Situ Recovery refers to in-place methods to extract the fuel component of a deposit. While shallow oil sands deposits can be removed by surface mining, dense heavy oils and deeply buried bitumen require in situ techniques

before they can be brought to the surface. These include thinning the oil to make it mobile and application of pressure to make it flow.

Natural Gas

Alberta's sales of natural gas increased by more than 5 per cent in 1993-94 from the previous fiscal year due to increased supply availability, greater demand in the markets that Alberta serves, and greater pipeline capacity to move this gas to markets.

Several pipeline expansions were completed which increased access to markets, particularly to California and the U.S. Pacific Northwest. Export pipelines operated at record levels and close to capacity because of rising U.S. demand for Canadian natural gas.

Prices — The average market price for Alberta natural gas in the 1993-94 fiscal year climbed to \$1.89 per thousand cubic feet (Mcf) from \$1.51 the previous fiscal year. Spot prices for intra-Alberta gas sales remained considerably above recent historical levels as a result of the tighter supply-demand balance within Alberta.

Prices in the U.S. market stayed fairly steady over the fiscal year, at a level reflecting the tighter supply-demand balance in the U.S. market. Over the winter of 1993-94, the northeastern U.S. experienced a record cold spell, seriously depleting storage levels. The U.S. also experienced relatively low drilling levels. These events helped to push up natural gas prices early in 1994. Alberta prices for sales to the U.S. market reflected prices in that market.

Production — Natural gas production increased from 3.7 trillion cubic feet (Tcf) in 1992 to 4.0 Tcf in 1993. (Production and reserves figures are calculated on a calendar-year basis). Export sales increased from 1.7 Tcf in 1992 to 1.9 Tcf in 1993. Sales to other Canadian provinces increased from 1.0 Tcf in 1992 to 1.1 Tcf in 1993, largely as a result of colder weather in Eastern Canada and economic growth. Intra-Alberta sales rose from 943 billion cubic feet (Bcf) in 1992 to 977 Bcf in 1993.

Reserves — At the end of the 1993 calendar year, Alberta's remaining established reserves were estimated at 54.4 Tcf, down from 56.6 Tcf at the end of 1992. The natural gas sector, like other industries, is starting to operate at lower inventory levels than in the past. While this reduces costs, it puts more emphasis on development and exploration activity to meet ongoing demands. As a result of higher prices for natural gas, drilling activity increased dramatically in the 1993-94 fiscal year to near record levels.

Regulatory Issues

Pacific Gas Transmission — The Pacific Gas Transmission pipeline, which supplies Canadian gas to California and the Pacific Northwest U.S., completed an expansion of 900 million cubic feet per day in November 1993, bringing total capacity on the line to about 2.5 billion cubic feet a day. The expanded pipeline system has been operating at about 75 per cent of its capacity since the expansion.

Order 636 — As a result of Order 636 from the U.S. Federal Energy Regulatory Commission, U.S. interstate pipelines completed restructuring to eliminate their merchant functions by the end of 1993. Order 636, a major regulatory change, required U.S. pipeline companies to unbundle their services. The intent of the order was to remove the competitive advantage that pipeline companies have enjoyed due to their previous integration of gas transportation and gas sales functions. The pipeline companies' 1993 actions as a result of the Order typically involved the buyout of supply contracts or assignment of these contracts to downstream buyers. Suppliers to U.S. natural gas pipelines received billions of dollars in transition costs as a result of this restructuring. Most Alberta producers were able to enter into alternate arrangements with downstream buyers and will continue to supply gas to U.S. markets.

Intra-Alberta Core Market Policy — During the 1993-94 fiscal year, the Department received comments on its March 1993 discussion paper and continued to develop policy that would give all consumers in Alberta the option to either purchase their natural gas from their local utility company, or from other suppliers. The Department was in the process of drafting regulations and consulting with interested parties at the end of the fiscal year.

Removal Permits — An Alberta Gas Removal Permit is required before natural gas may be exported from the province. The Alberta Energy and Utilities Board and the Department of Energy work together to issue these permits. Just over 700 applications for gas removals were processed by the Department in the 1993-94 fiscal year, well below the previous years total of close to 1000 applications. This reflected a streamlining of the Department's information requirements.

Rolled-in vs Incremental Pipeline Tolls — The Department continued to be involved in the tolling debate on a number of pipelines in the U.S. Alberta producers generally favour rolled-in tolling of new pipeline facilities, which requires all users of a pipeline to pay an equal toll for equal service. U.S. regulators have been adopting incremental tolling, under which users of expanded pipeline facilities pay all of the costs of a pipeline expansion. The debate on this issue continues.

NOVA Legislation — Legislation was introduced which will result in the repeal of the NOVA Act. This comes as a result of the corporate restructuring of NOVA Corporation of Alberta. Under the restructuring, their Alberta Gas Transportation Division (to be called NOVA Gas Transmission Ltd.) will now be regulated under the Gas Utilities Act.

Deliverability — Alberta's ability to meet peak market demand increased dramatically in the 1993-94 contract year as a result of increased well tie-ins, expansion of storage facilities, improved industry contracting practices, increased development activity and the use of electronic gas trading. These measures allowed Alberta to meet the much higher demand for Alberta gas in the marketplace, even during extremely cold weather late in the 1993-94 fiscal year.

No-notice Gas — The Department continued to work with industry to implement a market-based approach to ensure that Alberta consumers are assured of gas supply during peak periods and emergency situations.

Electronic Gas Trading — In the interests of promoting efficient market operation, the Department organized a seminar on electronic gas trading in September 1993. A discussion was held on the merits of electronic gas trading and several proponents demonstrated their systems. These systems will be developed by the private sector on a commercial basis.

Coal

Alberta has extensive coal resources and produces three general types of coal — subbituminous, bituminous thermal and bituminous metallurgical — at 11 major mining locations.

- Subbituminous coal is produced at 6 mines for use by Alberta utilities. These mines, all located in the Plains region, provide the basic fuel for most of Alberta's electric power generation.
- Bituminous thermal coal is produced at 2 mines. This high-heat value, low-sulphur coal is exported, primarily to Ontario and Japan where it is used in thermal power plants.
- Bituminous metallurgical coal is produced at 3 mines. Most of it is exported for use by the steel industry in Japan. Other markets include Korea, Brazil and Mexico.

Coal Market Development — Ontario Hydro's new contracts for coal supply from Alberta and British Columbia became operative in January 1993. The tonnages from Alberta were reduced significantly. As a result, the Action Committee on Western Canadian Low-Sulphur Coal became inactive, and is likely to be terminated. No new projects were initiated under this program.

Research and Technology — The Department supported research and technology in the areas of coal, hydrogen and mineral development. The overall goal of this R&D effort is to encourage the development of coal and mineral resources and hydrogen technologies; and to help Alberta's industry to remain competitive in both domestic and international markets. Coal research priorities are:

- reducing emissions from fossil fuel use (particularly coal);
- development of clean coal technologies; and
- developing new uses for coal.

Emissions — Coal-fired power stations provide approximately 90 per cent of the electricity generated in Alberta. Emissions of nitrous oxides (NO_x), which contribute to smog, are an important issue for Alberta's regulated utilities which are trying to reduce levels below that required by their operating licences. An applied research project was conducted at the coal-fired Sheerness Generating Station, near Hanna, Alberta, which examined low-cost options for NO_x reduction. Preliminary results suggest that through simple operational and maintenance modifications, the station might reduce its NO_x emissions by nearly 30 per cent, without investing in expensive low-NO_x burners or flue gas capture technologies. Further work needs to be done to ensure that these operational changes will not compromise other systems at the station. The Department also participated in an industry/government consortium to undertake a detailed study of emissions from all major power stations in Alberta, using the full fuel cycle methodology.

Competitiveness of Coal — Two ongoing studies are helping the coal-producing industry to improve their competitiveness in the short term. In the first study, researchers conducted on-site evaluations of coal preparation plants to gauge their efficiency and then make recommendations for increased productivity. Results to date indicate that for every 1 per cent improvement in plant efficiency implemented, coal companies can potentially increase their revenues by up to \$1 million/year from an incremental recovery of saleable fine coal. The second study is assisting in the development of a new market potential for Alberta export coal producers. The introduction of Pulverized Coal Injection (PCI) technology for steel making in Japan has resulted in a decrease in demand for traditional Alberta metallurgical coal. Therefore, this project has developed a computer model and has started pilot-scale furnace testing on a variety of Alberta and other Canadian coals to determine their suitability for use with this new PCI technology. Preliminary results indicate that Alberta coals may be well suited for PCI technology.

Hydrogen, Sulphur and Mineral Development

Alberta produces and uses 1.3 million tonnes of hydrogen from natural gas each year. This represents 60 per cent of the total hydrogen used in Canada. Hydrogen is the primary feedstock of Alberta's ammonia and fertilizer industry, the methanol industry and is used in the upgrading of oil sands and heavy oil.

The Alberta Hydrogen Research Program, funded jointly by industry and government, aims to make Alberta's energy industry more competitive. Hydrogen is a major cost of the upgrading of bitumen from the oil sands and will play an increasing role in petroleum refining with the introduction of reformulated gas lines. The program's overriding objective is to use hydrogen as a principal link for integrating the energy resource industry and developing the province's industrial base. The program is focused on:

- methods for reducing the cost of hydrogen production;
- the collection, transportation and distribution of new and surplus hydrogen to users; and
- using hydrogen in a more efficient manner in existing industries, particularly ammonia, methanol and bitumen upgrading as well as new industries.

Sulphur — Alberta is one of the largest sulphur producers in the world with outputs totalling 6.7 million tonnes in 1993, up from 5.8 million tonnes in 1992. Nearly all sulphur is produced from sour gas (H_2S) by the Claus process which converts H_2S into sulphur and water. The gas processing facilities account for 90 per cent of the total sulphur produced while oil sands and heavy oil upgrading generate

most of the remainder. Petroleum refining is a minor source of sulphur.

A new process to dissociate H_2S into its components, hydrogen and sulphur, has been developed under the program and is now being tested in the field.

Every year approximately 230,000 tonnes of hydrogen or 18 per cent of the hydrogen produced in Alberta is either vented, flared or used as low-quality fuel. Part of the problem has been the absence of a network to join hydrogen producers and consumers. In the 1993-94 fiscal year, a hydrogen pipeline demonstration project was initiated. This 30 km pipeline is designed to demonstrate that surplus raw hydrogen can be reliably and economically purified and distributed to local users.

Mineral Development — Although Alberta is the leading producer of energy minerals in Canada, the province has not been thoroughly mapped for industrial and metallic minerals. In 1992, Alberta signed an agreement with the federal government to support research in geoscience, technology and economic development of Alberta's non-energy minerals.

During 1993-94, the second year of this four-year Western Economic Partnership Agreement on Mineral Development, 13 geoscience research projects were carried out by the Geological Survey of Canada, 12 by the Alberta Geological Survey and three by Alberta's industry. Work in the technology development component of the program began in 1993-94 with 2 projects supported by the federal government and 3 by the Alberta government. The province also supported one project within the economic development component of the program.

Program results indicate good potential for the recovery of metallic minerals from Alberta's oil sands deposits, fine gold recovery technologies, and several industrial minerals such as aggregates, limestone, or calcium and magnesium chloride from Alberta brines. The program also significantly assisted the private sector in their intense exploration for diamond occurrences in Alberta. Research reports covering the wide range of geoscience research, mapping, technology and economic development activities for the first two years of the program have been made available to the public.

Electricity Supply

The generation of electricity in Alberta increased by 2 per cent in the 1993-94 fiscal year from the previous fiscal year. The main fuel source for electricity generation in Alberta is coal, accounting for 88 per cent of total generation. Most of the remaining generation is from natural gas and hydro facilities. A small amount of electricity (less than half of one per cent of total generation) is also generated by projects under the Small Power Research and Development Program and in isolated areas of the province using fuel oil.

Changes in Electricity Bills — Figure 11 shows the changes in electricity bills during the 1993-94 fiscal year. The increases resulted from the addition of new transmission, distribution and generation facilities, and higher natural gas generation costs due to natural gas price increases. Increases in electricity bills vary significantly depending on the customer group and time period chosen. For example, Alberta Power did not have an increase in its residential rates during the 1992-93 fiscal year while the other utilities did.

Figure 12
**Changes in Electricity Bills — March 31, 1993
to March 31, 1994**

	Resi- dential	Comm- ercial	Ind- ustrial	Farm
TransAlta Utilities (retail)	-3%	-1%	2%	-3%
Alberta Power	13%	8%	1%	15%
City of Calgary	0%	0%	0%	-
City of Edmonton	8%	2%	2%	-

Electric Energy Marketing Act (EEMA) — The Electric Energy Marketing Act was implemented in 1982 with a primary objective of reducing rate disparities throughout the province. The basic concept of EEMA is to average the costs of generation and transmission facilities province-wide — independent of utility ownership, franchise boundaries or geographic location.

An independent panel was struck in 1992 to conduct a public review of EEMA. Following a series of public hearings and over 500 written submissions, the panel recommended that Alberta move to partial equalization of generation and transmission costs.

The EEMA review panel's report was released to the public in February 1993 and the Minister of Energy asked stakeholders to provide comments on its recommendations. The panel's recommendation for partial equalization found little support with the electric utilities or customer groups. Some felt that the recommendation did not go far enough in addressing their perceptions that the EEMA mechanism is unfair and not sufficiently accountable. Others were concerned because they felt that their rates would increase if the recommendation was implemented. There was a recognition among stakeholders that EEMA options must be examined in conjunction with alternatives for the future structure and regulation of the electric industry.

The four largest electric utilities in Alberta were granted the opportunity to attempt to compromise on an alternative to the panel's recommendation for partial averaging but were unable to reach a consensus. The Minister of Energy then directed the Department of Energy to begin developing comprehensive alternatives for EEMA and the structure of the industry that could be considered by the Standing Policy Committee on Natural Resources and Sustainable Development.

In January 1994, the Minister of Energy met with a committee comprising mayors representing municipalities all over Alberta to ensure that they were kept up to date on the EEMA options being discussed and to provide a window for feedback from the municipalities. The Minister announced that the following principles should guide the consideration of options for EEMA:

Efficiency: The regulatory framework and industry structure should promote efficiency of the electric system through reliance on contracts, accountability, incentives and market forces where possible.

Fairness: There must be fairness in the treatment of historical facilities, in allocating risk and in avoiding major rate differences across arbitrary franchise boundaries.

On March 1, 1994, the department circulated to interested parties a paper entitled "*Identifying Options for the Alberta Electric Industry*." The paper identified 3 basic industry structure options and EEMA alternatives representing a spectrum of views that have been advanced by various stakeholders. Stakeholders confirmed that their vision of the Alberta electric industry was encompassed by the 3 basic options identified in the paper.

The Department of Energy worked with stakeholders to consider all or parts of these options in the Alberta context.

Small Power Research and Development — The principal objective of the Small Power Research and Development Program is to encourage production of electricity from renewable sources to help determine the role of renewable small power in meeting Alberta's future requirements. The program allows a maximum of 125 megawatts of renewable power to be developed and provides an incentive power purchase price.

As of the end March 1994, 18 projects had allocation including 5 that were under construction.

During the year, 3 projects failed to meet deadlines introduced into the Regulation in 1992.

Three wind projects were commissioned during 1993 including the 9-megawatt Cowley Ridge Project which is the largest operating wind-farm in Canada. Projects being developed under the program represent a variety of renewable energy technologies including small hydro, wind, and energy from biomass, peat, and waste wood.

CASA Priority Task B3 — Priority Task B3 under the Clean Air Strategy for Alberta (CASA) initiative directs the Department of Energy to "immediately extend its regulatory review of the electric power industry to cover energy efficiency and demand side management (DSM) considerations." A steering committee convened a workshop in March 1993 to give stakeholders an opportunity to exchange views on potential barriers to cost-effective DSM.

The steering committee submitted an interim report in June 1993 which described a number of the identified barriers. These included electric power regulatory barriers, environmental externalities, DSM market barriers and regulatory process barriers that stem from uncertainty about the role that regulated electric utilities should play in providing DSM services.

Demand side management (DSM) concerns initiatives directed at reducing electrical demand and energy consumption requirements. This places the focus on DSM's potential to displace supply-side resources.

"Externalities" occur when the activities of one party affect the activities of another party in ways that are not taken into account by the operation of the market.

Energy and the Environment

The Department of Energy addresses environmental concerns resulting from the development, production and consumption of energy resources. The focus is on integration of resource development and environmental protection and on development of initiatives to manage atmospheric emissions associated with energy production and use.

Integrated Resource Management — The Department subscribes to the philosophy of integrated resource management to ensure that resource-use decisions are made in the broader context of multiple land use. This presents the Department with the opportunity to review land and resource management policies, programs and objectives of participating government agencies. Such reviews ensure that programs are consistent with the government's overall plan for the management of Alberta's mineral resources. The Department reciprocates by sharing information on energy or mineral resource management initiatives with these agencies.

Integrated resource management is supported by the Department through a number of methods, the most formal of which is participation in the province's Integrated Resource Planning Program. The Operations and Support Division coordinates the Department's participation in the program.

In the 1993-94 fiscal year, the division worked to maintain opportunities for industry to gain access to, explore for and develop the mineral resources in each planning area. Progress was made on 11 Integrated Resource Plans (IRPs), 1 of which was approved for implementation. As well, the division participated in 2 major plan reviews which began in 1992. In all, 30 IRPs have been approved. The Department referred 25 petroleum and natural gas land lists and 143 individual, non-petroleum and natural gas land

descriptions to government departments to test for possible environmental land use conflicts.

The Department also participates in integrated resource management through a number of interdepartmental referral processes. During the year, 75 referrals were received for review and comment.

These referrals included: 1 preliminary disclosure to government by a proponent of a major energy or mineral development proposal; 3 Environmental Impact Assessments; 21 applications for surface dispositions for commercial tourism and recreation leases; 9 applications to designate lands for uses such as future parks, ecological reserves or wilderness and natural areas; and 41 miscellaneous applications. Each referral was reviewed for its impact on access for existing or proposed mineral development activity.

The Division also participated in 3 regional integrated decisions (RIDs), which are similar to integrated resource plans but with a local focus. The RIDs were designed to resolve oil and gas development access issues in environmentally sensitive and ecologically significant areas. Two RIDs were approved for implementation.

Caribou Conservation — The Operations and Support Division actively supported Alberta's caribou conservation efforts by participating in 5 regional caribou standing committees as well as the Provincial Caribou Strategy Task Force. These committees include the Northeast Region Standing Committee on Woodland Caribou, an excellent example of industry/government cooperation to resolve issues of mutual interest and concern. This committee is comprised of representatives from the energy, peat and forest industries as well as the departments of Energy and Environmental Protection. By pooling resources from industry contributions, grant funding and in kind services, the committee has been able to initiate and fund a multifaceted research program designed to increase understanding of caribou biology, caribou population dynamics and the effects of industrial operating conditions on the caribou range in northeastern Alberta.

Clean Air Strategy for Alberta — Throughout 1993-94, the Department of Energy devoted considerable attention to the Clean Air Strategy for Alberta. The Department coordinated the work of the 15 priority task groups, chaired 7 of those task groups, and played a major role in the formation of the Clean Air Strategic Alliance. The Deputy Minister of the Department of Energy was named President of the Alliance's Board of Directors, which held its inaugural meeting March 31, 1994.

The Clean Air Strategic Alliance is responsible for development and implementation of the Comprehensive Air Quality Management System for Alberta. The board of directors is actively responsible for defining clean air problems and setting priorities. Resources will be focused on developing solutions to the problems through collaborative processes involving major stakeholders. Results of work undertaken by the Alliance will be evaluated for environmental sustainability and cost-effectiveness. The effectiveness of the Alliance is dependent on the multi-stakeholder composition of the board of directors and task groups and on the commitment of each member to work cooperatively in addressing issues and solving problems.

National Air Issues Coordination — The Department participated in numerous activities related to climate change and other national air issues during 1993-94. In November 1993, Canadian energy and environment ministers formally established a National Air Issues Coordinating Mechanism. This mechanism coordinates national activities on issues such as climate change, acid deposition and urban smog. The Deputy Minister of the Department of Energy participates on the National Air Issues Steering Committee. The Department also participates at several levels of this mechanism. In particular, the Department is an active member of the Climate Change Task Group which has been given the responsibility of developing a National Action Program on Climate Change. The Department co-chairs working groups relating to climate change measures and assessment. The Department also

serves on working groups examining greenhouse gas inventories and emissions forecasting.

Environmental Legislation and Regulations — The Department was involved during 1993-94 in consultations aimed at developing regulations to the Alberta Environmental Protection and Enhancement Act, which was proclaimed in September 1993. The Department worked with representatives of the energy industry, the Alberta Energy and Utilities Board and Alberta Environmental Protection to ensure sound and cost-effective environmental legislation sensitive to the needs of the energy sector.

State of the Environment Reporting — During 1993-94, the Department participated on the State of the Environment Reporting Advisory Committee. Together with the departments of Environmental Protection, Agriculture and Health, the Department of Energy is developing a comprehensive State of the Environment Report which will, among other topics, describe the impacts that energy development and use has on the environment. It will also outline actions which are being taken to reduce these impacts.

Development of Analytical Tools — The Environmental Affairs Branch participates in the Stanford University Energy Modelling Forum (EMF), where energy experts, analysts and policy-makers meet to improve their understanding of the potential economic impact of critical energy problems and potential response strategies. During 1993-94, EMF studied the potential for energy efficiency improvements to reduce emissions and energy use. The forum also began an examination of the costs and benefits of various strategies for reducing greenhouse gases.

One tool which attempts to integrate economic and environmental considerations is being developed by the Canadian Energy Research Institute (CERI). The Environmental Affairs Branch assisted CERI in the development of an analytical tool which models impacts on the Alberta economy of various environmentally-related energy management options. This comprehensive model is designed to help in determining the optimal energy supply that will satisfy the energy demand while meeting policy and environmental objectives.

Southwest Alberta Renewable Energy Initiative

(SWAREI) — SWAREI, the largest renewable energy program in Western Canada, was established in 1989 and concluded its final year of operation in 1993-94. In its four years of operation, SWAREI spent \$2.74 million from the Alberta Heritage Savings Trust Fund to help develop 12 renewable energy related projects. The 6 electrical generation SWAREI projects received 23.2 MW of power generation from the Small Power Research and Development Program.

The Department will continue to support renewable energy development in 1994-95 by providing funds to assist the Town and Municipal District of Pincher Creek in privatizing the former Alberta Office of Renewable Energy Technology Information Centre and to help support the Alberta Renewable Energy Test Site.

Energy Efficiency — In February 1994, the Department announced that it would take steps in privatizing the program functions of the Energy Efficiency Branch. These programs included energy efficiency awareness, information and education services.

The Department concluded that the market for specialized products and services in the energy efficiency area had grown and become increasingly sophisticated. Other levels of government, public utilities, equipment manufacturers and many not-for-profit organizations now provide information and services in this area. The Department therefore made the decision to transfer the delivery of energy efficiency programs to the private or not-for-profit sector. This was expected to result in a cost savings of \$1.1 million in 1994-95.

The Department maintains a policy role in energy conservation and efficiency. This includes developing policies that directly or indirectly encourage energy efficiency.

Finance and Administration

Financial Services — Financial Services is responsible for all aspects of the financial operations of the Department of Energy, including revenue management, accounts payable, financial planning, and financial statements. Activity increased in all areas in 1993-94, largely because of the development of the Department's three-year business plan, and the resulting budget reduction strategies. Major gains were made in making optimal use of internal resources in the revenue management area, with processes being refined to provide significant manpower savings. Over the fiscal year, \$3.1 billion in energy-related revenue was processed. Through the Corporate Accounting and Reporting System (CARS), the area manages revenue and accounts receivable information for both the Department of Energy and the Department of Environmental Protection.

Information Systems — This area provides leadership in developing business information systems for the Department. It also supports the operation of these systems and provides specialized technical expertise for existing information and office systems. During 1993-94, it worked to develop and put in place a department-wide electronic communications infrastructure to meet the increasing demand for broad access to information and exchange of information. The area also undertook strategic planning to develop a corporate information system, which will bring together business and information technology planning. This will result in a consistent direction for systems development across the Department. The first phase of this strategy has focused on gas royalties.

Human Resources — The Human Resources Branch is an internal consulting group that provides planning and support related to staffing, job evaluation, performance management, staff development, organizational design, health and safety, and pay and benefits. During 1993-94, the Branch assisted with organizational and operational strategies resulting from the restructuring of the Department and the amalgamation of agency staff into the department. Emphasis was placed on managing change, operating within a team-oriented organization, along with developing employees to meet new skill requirements resulting from staff reduction programs.

Corporate Records Management and Extension Services — This area manages the Department's file information, which includes file classification standards, micrographic, file system development, records management and mail and courier services. During 1993-94, work was initiated on expanding the Records Management Program to include the Alberta Petroleum Marketing Commission, the Alberta Oil Sands Technology and Research Authority and the Department of Environmental Protection. This will broaden the information base and help to provide a one-window access to information.

The Accommodation Services Branch coordinates accommodation planning, furniture management, telecommunications and parking. During 1993-94, development was started on a Ministry-wide accommodations plan designed to more closely integrate various agencies within the Department. These agencies became part of the Department of Energy under restructuring plans announced in February. The accommodation plan will reduce the amount of space leased by the Department and help to identify duplicated functions.

Internal Audit — Internal Audit examines the financial activities of the Department to ensure that internal accounting and operating controls function properly. Compliance and financial audits were completed during the 1993-94 fiscal year, including a review of the revenue accounting area within the Corporate Accounting and Reporting System. Since November 1993, the audit staff have worked almost exclusively with the development team of the Mineral Revenues Information System (MRIS). MRIS has been developed to simplify revenue collection by the Department.

Financial Statements

Alberta Department of Energy Statement of Revenue for the Year Ended March 31, 1994

	1994 (\$000)	1993 (\$000)
Taxes:		
Freehold mineral rights tax	83,824	72,610
Other	0	1
	83,824	72,611
Non-Renewable Resource Revenue:		
Crude oil royalty	766,485	1,008,545
Natural gas and byproducts royalty	1,410,413	1,069,313
Synthetic crude oil & bitumen royalty	66,446	64,941
Coal royalty	13,687	15,992
Bonuses and sales of Crown leases	717,097	167,485
Rentals and fees:		
Petroleum and natural gas	93,786	88,617
Oil sands	6,906	7,472
Coal	2,459	3,996
Other	1,383	2,430
Other	144	10
	3,078,806	2,428,801
Transfers from Government Enterprises:		
Alberta Petroleum Marketing Commission	3,749	4,245
Other Revenue:		
Refunds of expenditure	459	153
Miscellaneous	766	711
	1,225	864
Total Revenue	\$3,167,604	\$2,506,521

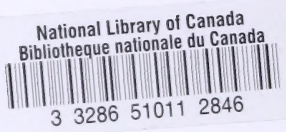
Alberta Department of Energy
Statement of Departmental Expenditures
For the Year Ended March 31, 1994

	1994 (\$000)	1993 (\$000) (Restated)
Finance and Administrative Services	11,391	11,423
Mineral Management		
Mineral Resources	6,833	7,723
Mineral Revenues	12,957	15,179
Markets, Supply and Industry Analysis	2,735	3,063
Sustainable Energy Development	6,886	6,963
Mineral Revenues Information System (Note 2)	4,328	0
	33,739	32,928
Central Support Services	1,127	1,263
	\$46,257	\$45,614

Note 1: Alberta Oil Sands Equity, Alberta Petroleum Marketing Commission, Alberta Oil Sands Technology and Research Authority and Alberta Public Utilities Regulation are not included in the Statement of Expenditures.

Note 2: Fiscal 1993-94 was the first year of the planned three-year development period for the Mineral Revenues Information System (MRIS). Funding for MRIS was provided by reallocating funds from other areas of the Ministry and no funding has been required from Treasury.

Note 3: 1993 figures have been restated where necessary to conform to the 1994 presentation.



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